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DIRECT TESTIMONY OF

NEVILLE O. LORICK

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2000-0170-E

Q. PLEASE STATE YOUR NAME, BUSINESS ADDRESS AND POSITION WITH SOUTH CAROLINA ELECTRIC AND GAS COMPANY (SCE&G).

A. Neville O. Lorick, 111 Research Park, Columbia, South Carolina. My position is Vice President of the Fossil & Hydro Strategic Business Unit (SBU) at South Carolina Electric &Gas Company (SCE&G).

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I have a B. S. in Mechanical Engineering from The University of South Carolina. I began my employment tenure with SCE&G in April 1971, as a Student Assistant. I was hired full time in January 1975, as an Engineer. In March 1978, I became the Assistant Plant Manager for our Canadys Station Fossil Steam Plant and in September 1982, was promoted to Plant Manager. In July 1988, I was promoted to General Manager, Fossil and Production Operations. In this position, I was responsible for all of the Company's Fossil Fuel Plants and the Fossil Production Corporate Staff. In December 1992, with reorganization, my title was changed to Manager of Production Support. In December 1994, I was named Manager of Operation Services and my responsibilities included the management of Support Staff and their interface with the Fossil/Hydro Departments. In July 1995, I was promoted to my current position of Vice President of Fossil & Hydro Operations. My responsibilities include the overall accountability for the planning and direction of the operations, maintenance and administration of the fossil-fueled, hydroelectric, and natural gas turbine power plants within the Fossil & Hydro SBU. Additional responsibilities include management of the Lake Murray Impoundment and the Power Block Group.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide to the Commission an overview of the comprehensive planning that the Company has undertaken in connection with the Urquhart Re-powering Project; to explain to the Commission how we at SCE&G arrived at the decision embodied in this application; and to discuss why we believe this decision best addresses the needs of the Company and our customers.

The decision of SCE&G is to acquire and install two new combustion turbine-generators at our Urquhart Station in Beech Island, Aiken County. The witnesses who will follow me on the stand will discuss with the Commission each step of our planning process and provide our analysis and support for each decision made. Dr. Joseph Lynch will offer the evidence to support our assessment of the capacity need for electric power in the SCE&G service area and why we believe the assessment is correct. He will also discuss the financial and economic reasoning that underlies the decisions we have made to undertake re-powering at Urquhart. Mr. Skip Smith will offer a more detailed description of the production system and the contract arrangement with Duke-Flour Daniel for the engineering, procuring, and constructing of the project. Mr. Jack Preston will address the environmental considerations involved with the Urquhart plant site and affirm the Company's commitment to protecting the environment. Finally, Mr. Charles White will explain the ancillary construction of a substation and a transmission line which is required to integrate this enhanced power production into the Company's grid, including any environmental considerations affecting the transmission aspect of the project.

Through this testimony we will demonstrate to the Commission that our decision-making has been consistently aimed at providing reliable, safe, high quality, cost-effective power for the customers of SCE&G. In all these considerations our decisions reflect our best judgment.

Q. PLEASE EXPLAIN TO THE COMMISSION HOW SCE&G INITIATED THE PROCESS THAT LED TO THE DECISION FOR THE URQUHART RE-POWERING PROJECT.

A. This process emerged from SCE&G's annual load and resource forecast. Based on our projections of growth in peak demand on our system after the year 2000, we anticipate a supply shortfall of 268 megawatts by 2002 and 460 megawatts by 2004. These numbers clearly indicate to us that the need for additional capacity is real and warranted. Let me note here that the current minimum reserve margin is 497 megawatts. Dr Joseph Lynch's testimony will address this assessment of the electric power capacity need in considerable detail.

Having recognized a need for additional electric power, Company personnel began a two-track course of action to determine how best to provide for the added capacity. Simultaneously, SCE&G issued a Request for Proposals (RFP) to purchase the supply capacity and initiated analyses regarding the requirements and feasibility of self-building additional generation.

Q. PLEASE EXPLAIN TO THE COMMISSION HOW THE REQUEST FOR PROPOSALS OCCURRED.

A. On October 9, 1998, SCE&G issued a RFP to purchase 100 to 300 megawatts of dispatchable supply-side electric capacity and associated energy beginning May 1, 2001. The Company invited proposals for electric generation including unit power, system power, and merchant plants.

The RFP was distributed to 54 companies including investor-owned utilities, marketers, and independent power producers. The Company received 18 proposals from 10 companies in late November 1998. Please see my Exhibit No. _____ NOL-1. The following proposals were immediately rejected due to failure to meet the basic requirements of the RFP:

1) American Electric Power (AEP): AEP delivered two proposals. AEP Proposal 1 offered a contract for 100 MW of energy delivered to the SCE&G/Duke interface from the AEP system during the standard 16 hour on-peak schedule (HE 0800 – 2300) for the period May 1, 2001 through December 31, 2005, scheduled daily. AEP Proposal 1 was rejected because energy proposed for delivery could not be considered capacity-backed energy by SCE&G. It would have a service priority after AEP's

internal load. AEP Proposal 1 was also complicated by a lack of dispatch flexibility inherent in the 16 hour on-peak schedule. AEP Proposal 2 offered an annual option for 50 MW of energy delivered to the AEP Bus during the standard 16 hour on-peak schedule (HE 0800 – 2300). SCE&G would pay AEP an Option Premium for the right to call on this option annually for 2002 and 2003. AEP Proposal 2 was rejected due to the lack of dispatch flexibility and because the offered contract term was not consistent with SCE&G's need.

2) Citizens Power Sales (Citizens): Citizens offered a contract for100 MW of capacity and energy delivered to Citizen's choice of SCE&G interfaces during the standard 16 hour on-peak schedule (HE 0800-2300) for the period of May 1, 2001 through May 30, 2005, scheduled daily. Citizen's proposal was rejected due to inadequate dispatch flexibility, high monthly capacity pricing, and a high contract heat rate.

3) Carolina Power & Light (CP&L): CP&L delivered two proposals to SCE&G. CP&L Proposal 1 was selected as a short-list proposal, which will be discussed later. CP&L Proposal 2 offered a contract for up to 100 MW of System Power from the CP&L system for 2001 and up to 300 MW of System Power from the CP&L system for 2002-2005. CP&L Proposal 2 was rejected due to high monthly capacity pricing.

4) Morgan Stanley (MS): MS offered a contract for up to 120 MW of peaking capacity for an unspecified period. The MS proposal lacked detail and was incomplete; therefore, it was rejected.

5) PECO Energy (PECO): The PECO proposal offered a contract for up to 300 MW of capacity and energy for the period of January 1, 2001, through December 31, 2005, with prior day scheduling. This proposal was rejected due to inflexible dispatch requirements.

6) Virginia Power (Virginia): Virginia delivered two proposals to SCE&G. Virginia Proposal 1 was selected as a short-list proposal, which will be discussed later. Virginia Proposal 2 offered a contract for up to 264 MW of Unit Power from Virginia's Batesville Generation Facitlity in Batesville, Mississippi. Virginia Proposal 2 was rejected due to inadequate dispatch flexibility and high capacity pricing.

Q. PLEASE CONTINUE TO DESCRIBE FURTHER DEVELOPMENTS IN THE RFP PROCESS.

A. Subsequent to the eliminations described above, a short-list of proposals was considered. SCE&G met with representatives from each of these proposing companies in Columbia in January and February 1999. In order to judge the flexibility and potential constraints of each proposal, proposers were given a number of hypothetical dispatch scenarios occurring throughout a typical year and asked how they would respond. These dispatch scenarios included both normal operations and operations with short start times, high market prices, and natural gas curtailments. Each company presented its proposal and answered questions. The following outline summarizes each short-list proposal:

1) Cogentrix/Dynegy Partnership (Cogentrix): Cogentrix presented four proposals including:

a) Two 150 MW Natural gas fired turbines

b) Four 75 MW Natural gas fired turbines

c) Two 150 MW No. 2 fuel oil fired turbines

d) Four 75 MW No. 2 fuel oil fired turbines

Cogentrix' pricing included fixed monthly capacity payments and energy prices based on indexed gas prices and a contract heat rate. All four proposals required SCE&G to submit prior day energy schedules with Cogentrix retaining unused capacity and energy for resale to others. In the event that SCE&G needed energy not scheduled on the prior day, SCE&G would be liable for lost net revenue including liquidated damages resulting from any Cogentrix sale to a third party. Given the volatility of the wholesale electric market, SCE&G's potential liability was a matter of concern. That concern notwithstanding, Cogentrix' first two proposals advanced to the next round of review since they included natural gas fired turbines, but the latter two proposals were eliminated because of environmental considerations related to their exclusive dependency on No. 2 fuel oil.

2) Carolina Power & Light (CP&L): CP&L presented its Proposal 1 for up to 100 MW of Unit Power in 2001 and up to 300 MW of Unit Power in 2002-2005 delivered to any SCE&G interface. CP&L's pricing included fixed monthly capacity payments and energy prices based on indexed gas prices and a contract heat rate. CP&L's proposal specified capacity from a planned unit in Duke Power's control area. Based on a comparative

analysis, this proposal of CP&L was not as economically favorable as other responses and was eliminated from consideration.

3) Enron Capital & Trade Resources Corp. (Enron): Enron presented a proposal for 100 MW of Unit Power delivered to the SCE&G/Duke interface for the period May 1, 2001 through April 30, 2002 and 300 MW of Unit Power delivered to the SCE&G/Duke interface for the period May 1, 2002 through April 30, 2011. Enron's pricing included fixed monthly capacity payments and energy prices based on indexed gas prices and a contract heat rate. Enron's proposal was advanced to the next stage of review.

4) Sonat Power (Sonat): Sonat presented a ten year proposal (beginning June 1, 2002) for 318 MW of Unit Power from two units to be built on the SCE&G system. Sonat's pricing included fixed monthly capacity payments and energy prices based on indexed gas prices and a contract heat rate. Sonat's proposal was advanced to the next level of review.

5) Southern Wholesale Energy (Southern): Southern offered a contract for 78 MW of Unit Power beginning May 1, 2001 and 156 MW of Unit Power beginning in 2002. Southern offered SCE&G contract terms of five, seven, or ten years, with price differentials for each term. Southern proposed construction of the new units in the Southern control area. Southern's pricing included fixed monthly capacity payments and energy prices based on indexed gas prices and a contract heat rate. All three of

Southern's proposals were eliminated because they were not economically competitive.

6) Virginia Power (Virginia): Virginia Proposal 1 offered a contract for 300 MW of Unit Power for the period May 1, 2001 through April 30, 2006 from a unit to be constructed in either the SCE&G or Southern control area. Virginia's pricing included fixed monthly capacity payments and energy prices based on indexed gas prices and a contract heat rate. Virginia's Proposal 1 was eliminated because of a lack of certainty of available equipment related to a pending proposal for Virginia's native load generation. In essence, Virginia's native load would take priority over any availability of power for use in South Carolina.

Q. WHAT ACTIONS OCURRED NEXT IN THE ASSESSMENT OF REMAINING PROPOSALS UNDER THE RFP?

A. Following the discussions described above, SCE&G began evaluation of the remaining four proposals: Cogentrix Proposal 1, Cogentrix Proposal 2, Enron, and Sonat. These remaining proposals were considered either technically acceptable or near technically acceptable, pending slight modification. Cogentrix Proposal 2, except for smaller turbine size, was essentially the same as Cogentrix Proposal 1, so the latter was a better proposal by this company for SCE&G to carry forward for final review. Sonat's proposal was eliminated at this point because it was not economically competitive with the others. As a result of these two eliminations, only Cogentrix Proposal 1 and the proposal of Enron were deemed truly competitive off-system possibilities. SCE&G then focused on the long-term financial impacts of each of these latter two proposals. The competitive analysis of these proposals with other alternatives will be discussed by Dr. Lynch.

Q. PLEASE DISCUSS THE NEXT STEPS IN THE GENERAL EVALUATION PROCEDURE ASIDE FROM THE RFP PROCESS?

A. Based on Dr. Lynch's analysis, SCE&G determined that self-building two 150 megawatt simple cycle gas turbines in South Carolina would meet the Company's objectives of reliable and economical generation capacity better than the other proposals received by way of the RFP. Further evaluation and consideration of the aging Urquhart facilities led the Company to determine that re-powering Urquhart Units 1&2 in a combined cycle configuration would be most beneficial. This conclusion was derived in the following manner.

In parallel with the RFP process we initiated a study to develop a site specific self-build alternative against which we would evaluate the off-system proposals. In early October 1998, meetings were held with representatives from the generation, transmission, and environmental groups of the Company to discuss siting for a self-build alternative. These factors, together with the opportunity to share some infrastructure and manpower with the steam plant at the Cope site, initially suggested that Cope was the preferred location.

Duke/Fluor Daniel (D/FD) was selected to prepare a cost estimate for a nominal 300 megawatt simple-cycle combustion turbine installation at Cope. D/FD was selected because of its intimate knowledge of the Cope plant and site (D/FD was the Engineering, Procurement, and Construction contractor for Cope) and because it had recently performed a similar study for SCE&G for a site elsewhere in the state. D/FD completed this study on December 1, 1998. This study included a project scope, schedule and cost estimate. The project was based on two General Electric 7FA combustion turbines burning natural gas with #2 fuel oil as a back-up when gas is curtailed. The two units had a total net summer output of 290 megawatts at a 10,860 Btu/kWh (HHV) heat rate. The total cost of this project including contingencies, taxes, start-up costs and interest during construction was estimated to be $98,616,000 in 1998 dollars, or $340 per KW.

This information together with estimates of fixed and variable O&M was then provided to SCE&G's Corporate Planning Department for use in evaluation against the off-system proposals. Using total (fixed and variable) cost per MWH delivered to the SCE&G system as the criteria, the self-build alternative had a clear advantage over the most competitive off-system proposals, (Cogentrix 1 and Enron) particularly over the long term. The results were presented to senior staff on March 29, 1999. The recommendation from senior staff at that time was to self-build, but it also directed that further evaluation be done to identify the best self-build option.

Q. WHAT OTHER CONSIDERATIONS ENTERED INTO THIS EVALUATION PROCEDURE?

A. During this same time frame, significant work was being done to determine SCE&G's strategy for complying with nitrous oxides (NOx) and sulfur dioxide (SO2) environmental regulations for our coal fired units. We determined that a major capital expenditure for adding a Selective Catalytic Reduction (SCR) system to Cope station could be avoided if NOx emissions from Urquhart units 1

& 2 were significantly reduced as a result of repowering them using combustion turbines. This would also eliminate many capital and O&M expenditures required to maintain the reliability of Urquhart 1&2 as well as eliminating the cost of purchasing allowances for the SO2 produced while burning coal.

Because of environmental concerns, SCE&G also gave consideration to re-powering Urquhart Station as a fluidized bed plant and adding two 150 MW combustion turbines. The cost of this alternative, however, made it readily apparent that this option was not viable. Dr. Lynch addresses this comparison further in his analysis.

In April 1999 we contracted with Sargent & Lundy to evaluate the technical issues and estimate the cost to re-power Urquhart units 1 & 2. Re-powering, in this case, involves retiring the old coal fired boilers used to generate steam and replacing them with combustion turbines and boilers that use the heat in the combustion turbine exhaust to generate steam. That steam would drive the existing Urquhart 1&2 steam turbine generators. The Sargent & Lundy study confirmed the technical and economic feasibility of re-powering the Urquhart units using combustion turbines.

The Corporate Planning Department then compared the cost of this Re-Powering Project at Urquhart with that of other alternatives, including the option to invest in the Urquhart units to extend their life, add two simple cycle turbines at Cope, and install an SCR system at Cope. Adding two simple cycle turbines at Cope entailed estimated capital costs of $104 million in 2001 dollars (an increase from a previous estimate based on 1998 dollars). Alternatively, the total project cost associated with re-powering the two units at Urquhart came in at just over $256 million. This total, however, would be significantly offset by avoiding expenditures of $36 million for extending the useful life of current facilities at Urquhart and by eliminating the expenditure of $45 million for the SCR system at Cope. Furthermore, the Urquhart Re-powering Project would have the additional benefit of lowering SO2 emissions and would also decrease annual production expenses in the range of $20 million.

In short, all this led to the conclusion that the self-build option, with a total project cost of $256,035,641, which includes AFUDC, was a better comprehensive solution to all requirements which the Company has to address. Skip Smith's testimony, which follows, will provide a detailed description of this project and its costs.

Q. MR. LORICK, WERE THERE ANY OTHER FACTORS THAT ENTERED INTO THE DECISION-MAKING PROCESS?

A. Yes, another important aspect of the decision-making process related to the availability and volume of natural gas that would be necessary for the operation of the proposed combined cycle turbine-generators at the Urquhart Station.

Q. WHAT FUEL WILL BE USED TO FIRE THE PROPOSED GAS TURBINE UNITS AT URQUHART?

A. These units will burn natural gas as the primary fuel, with distillate (No. 2) fuel oil as the secondary fuel.

Q. HOW WILL NATURAL GAS BE SUPPLIED?

A. The Urquhart plant site is located on the Savannah River near the point where South Carolina Pipeline Corporation (SCPC) connects with and receives natural gas from Southern Natural Gas Company's interstate pipeline. The existing units at this site burn natural gas, which are supplied by SCPC through approximately three miles of pipe. The current pipe will have to be upgraded to deliver the increased volumes of natural gas required by the proposed units.

Q. WHAT VOLUMES OF NATURAL GAS WILL BE REQUIRED AND UNDER WHAT CONTRACT TERMS?

A. The two new units will consume approximately 86,000 dekatherms (DT) of natural gas a day at 100% load factor. The Company plans to contract with SCPC for a 50,000 DT of firm natural gas supply and to contract for the balance on an interruptible basis. This will allow the units to be available and utilized when the electric generation economic dispatch model dictates their need.

Q. INTERRUPTIBLE NATURAL GAS IS NOT ALWAYS AVAILABLE. HOW WILL THE PLANTS BE FIRED IF NATURAL GAS IS INTERRUPTIBLE?

A. The peak period for electric usage is in the summer time when there is very little, if any, curtailment of natural gas supply. It is planned to have natural gas available to burn at all times except the severe winter period. When natural gas is not available, we will fire the units on distillate oil. The Company will have oil storage tanks with 2.4 million gallons capacity to supply these units.

Q. MR. LORICK, DO YOU HAVE ANY OTHER COMMENTS TO MAKE TO THE COMMISSION?

A. Yes. All these factors which I have discussed were measured and carefully evaluated by SCE&G's senior management, and this process resulted in a recommendation to proceed with the Re-powering Project at Urquhart. Senior staff carried this recommendation to the SCANA Board of Directors on August 11, 1999, and the Board accepted the President's recommendation. Now the Company is before the Commission respectfully seeking its approval of the Urquhart Re-Powering Project.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

EXHIBIT NO. _____ (NOL-1)

	Eliminated Immediately	Eliminated after Short List Presentation	Eliminated during final discussions	Reasons for Elimination Included:
AEP Proposal 1	X			Not Capacity-backed.
AEP Proposal 2	X			Lack of dispatch flexibility, term not consistent with SCE&G need.
Citizens	X			Inadequate dispatch flexibility, high pricing.
Cogentrix/Dynegy Proposal 1			X	Long-term economics of SCE&G self-build superior.
Cogentrix/Dynegy Proposal 2			X	Long-term economics of SCE&G self-build superior.
Cogentrix/Dynegy Proposal 3		X		Lack of environmental feasibility.
Cogentrix/Dynegy Proposal 4		X		Lack of environmental feasibility.
CP&L Proposal 1		X		Not comparably economic
CP&L Proposal 2	X			Not comparably economic
Enron			X	Long-term economics of SCE&G self-build superior.
Morgan Stanley	X			Incomplete proposal.
PECO	X			Inadequate dispatch flexibility
Sonat			X	Long-term economics of SCE&G self-build superior.
Southern Proposal 1		X		Not comparably economic
Southern Proposal 2		X		Not comparably economic
Southern Proposal 3		X		Not comparably economic
Virginia Proposal 1		X		Turbine availability not known due to RFP for Virginia native load.
Virginia Proposal 2	X			Inadequate dispatch flexibility, high pricing.

DIRECT TESTIMONY OF

JOSEPH M. LYNCH

ON BEHALF OF

SOUTH CAROLINA ELECTRIC & GAS COMPANY

DOCKET NO. 2000-0170-E

Q. Please state your name, business address and current position with South Carolina Electric and Gas Company.

A. Joseph M. Lynch, 1426 Main Street, Columbia, South Carolina. My current position is Manager of Resource Planning.

Q. Describe your educational background and professional experience.

A. I graduated from St. Francis College in Brooklyn, New York with a Bachelor of Science degree in mathematics. From the University of South Carolina I received a Master of Arts degree in mathematics, an MBA and a Ph. D. in management science and finance. I was employed by SCE&G as a Senior Budget Analyst in 1977 to develop econometric models to forecast electric sales and revenue. In 1980 I was promoted to Supervisor of the Load Research Department. In 1985 I became Supervisor of Regulatory Research where I was responsible for load research and electric rate design. In 1989 I became Supervisor of Forecasting and Regulatory Research and in 1991 I was promoted to my current position of Manager of Resource Planning.

Q. Briefly summarize your current duties.

A. As manager of Resource Planning I am responsible for producing SCE&G's forecast of energy, peak demand and revenue; for developing the Company's generation expansion plans; and for overseeing the Company's load research program.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to demonstrate the need for additional capacity by presenting the Company's load and resource forecast and reserve margin requirements and to show that the Urquhart Re-powering Project is the most cost effective option.

Q. Discuss the Company's growth in peak demand.

A. The peak demand on our system is shown in Exhibit No. _____(JML-1). The graph shows the actual peak demands from 1985 through 1999 as well as those projected for 2000 through 2009. As can be seen in the graph we expect the historical growth in peak demand to continue through the forecast period. The average annual change in peak demand over the 15-year period from 1985 to 1999 was 104 megawatts per year and the average change over the next 10 years from 2000 to 2009 is forecasted to be 100 megawatts per year.

Q. Discuss the Company's projected capacity needs?

A. The purpose of Exhibit No.______(JML-2) is to show the Company's need for more capacity. It contains the Company's projected firm peak demand in column (C). The firm peak demand is the difference between our gross peak and our demand side management (DSM) capacity. It is also the level of demand that the Company plans to meet with a firm supply. Our supply required is shown in column (E) of Exhibit No._____(JML-2). This is the sum of the firm peak demand and our minimum reserve margin requirement of 497 megawatts. Column (G) shows our supply shortfall. This is the difference between our existing supply capacity of 4,543 megawatts and the projected supply capacity requirements. By 2002 we project a supply shortfall of 268 megawatts and by 2004, 460 megawatts. At present the Company plans to cover the 61 MW capacity shortfall in 2000 with market purchases and will decide about the 2001 shortfall sometime after the summer of 2000.

Q. Briefly describe how you forecasted the firm peak demand.

A. The first step in forecasting the peak demand is to forecast the annual energy by class of customer. The seven major classes of customers are residential, commercial, industrial, other public authorities, public street lighting, municipalities and cooperatives. In all we have developed over 100 econometric and time series models relating energy consumption, customer growth, weather and economic variables. In the short term we produce forecasts in great detail, in most cases by rate and class and SIC code where appropriate. In short term forecasts, which we define as forecasts for the next two years, we rely heavily on weather correlation models, recent growth trends, industrial production indices and information from large customers about their upcoming expansion plans. In the longer term we rely on annual models that correlate energy consumption with population growth, income growth, employment growth and industrial production. Once the energy forecast is made the second step is to analyze the load characteristics of each customer class and to derive average coincident load factors to estimate the peak demand related to that class' level of energy consumption. These load factors come from the Company's Customer Load Survey Program, which has been in place since the early 1970s.

On average our forecast error over the last several years is about 1%.

Q. What are the major assumptions used in the forecast?

A. We rely on Standard & Poor's Data Resources International (DRI) for the historical and projected economic variables for the State of South Carolina and its counties, as well as for the nation. DRI is a well-known economic forecasting firm owned by The McGraw-Hill Companies. We also base our forecasts on normal weather which we define as the average weather over the last 15 years. In previous years we used a 30-year average but we have found that the 15-year average approximates the next succeeding year's weather more closely. The 15-year average weather results in a small increase in forecasted sales of 0.3%. In summary, we conclude that the economic growth that our service territory has seen in the past will continue in the future and that our customers' energy and demand needs will grow accordingly.

Q. Describe the Company's existing supply capacity.

A. The Company will have 4,543 megawatts of supply available the summer of 2000. Exhibit No.___(JML-3) shows the composition of this supply.

Q. What demand-side resources are available?

A. The Company has 248 megawatts in demand-side resources. Under the umbrella of demand-side resources, we include interruptible load (196 megawatts) and standby generation (52 megawatts).

Q. Does the Company have any conservation or efficiency based DSM programs?

A. The Company is a strong proponent of the wise use of energy. In the past the Company has offered a number of conservation-type programs subsidizing the installation of high efficiency equipment and increased levels of insulation. These programs have helped to raise customer awareness and helped encourage more stringent building codes and appliance standards. The impact of these efficiency measures on customer consumption is captured by our statistical models and reflected in our projections.

Q. What is the Company's minimum reserve margin?

A. At present the Company believes that the prudent level at which to set the minimum reserve margin is 497 megawatts. This represents a reserve margin percentage in 2000 of 12.1%. This reserve level is lower than the 20% that the Company and much of the industry maintained in the past. For a number of reasons, however, the Company believes that it is not now desirable to carry this level of reserves. From a planning perspective our load growth is slower, about 2% on average, and more predictable than the load growth of the 1960s and early 1970s when load grew at the 7% level. Additionally, for the foreseeable future only gas-driven power plants will be built. This means a 2-3 year time frame for adding capacity instead of the approximately 5-6 year period required for a coal plant. From an operational perspective, because of improved maintenance techniques, especially preventive techniques, our power plants are more reliable today than in the past. Finally, changes in the market must be considered. The wholesale market is very competitive and becoming more efficient each year. Moreover, retail open access will bring with it the threat of stranded costs. Prudence requires a careful approach to the addition of new generation capacity.

Q. Please explain your reserve margin of 497 megawatts.

A. There are three components to the 497 MW reserve margin. They are: operating reserves (197 megawatts), contingency reserves (200 megawatts) and weather reserves (100 megawatts). The sum of these three components makes up the 497 megawatts. The operating reserves are set at 197 megawatts. This is the capacity that the Company is required to make available as part of its operating agreement with the other members of VACAR. VACAR is the Virginia-Carolina sub-region of SERC, the Southeast Reliability Council. Contingency reserves, which are set at 200 megawatts, are needed to address the risk that some units may be down-rated or forced out because of mechanical problems or environmental constraints. The weather reserves are set at 100 megawatts. Based on statistical work correlating load with weather, we believe an additional 100 megawatts of capacity is currently sufficient to cover an increase in peak load related to abnormally hot weather.

Q. Discuss the process that led from the need for capacity to the Urquhart Re-powering Project.

A. After quantifying the need for some form of capacity, the next step was to determine what type of supply to add. There were two overall steps in this process. Our first step was to determine whether it was better to purchase the supply capacity or to build a new unit. To answer this question, the Company issued a Request for Proposals (RFP), the best responses to which were compared to self build. This process was discussed by Mr. Neville Lorick. Mr. Lorick explained that based on analysis of the responses it was determined that the self-build option was the better alternative. Our second step involved deciding what type of capacity to build. The result of this step was the Urquhart Re-powering Project.

Q. How did you conclude that the self-build option was superior to the RFP alternatives?

A. Exhibit No. _____(JML-4) shows a graph of the incremental revenue requirements related to the self-build option and the two best RFP alternatives. The components of these revenue requirements include demand-related charges, fuel costs, startup costs and fixed and variable O&M costs. The graph shows these costs on a dollar per MWH basis. It is clear from this graph that the self-build option is the lowest cost option. In addition, this option had the added value of increased dispatch flexibility since it would be owned by SCE&G.

Q. Explain why the Urquhart Project is superior to building the two CTs.

A. After concluding that building two CTs of 150 MWs each was a superior option to a power purchase alternative, we analyzed how these CTs would fit into our fleet of existing plants. In particular we looked at the capital expenditures required in the future to keep all our plants running reliably and especially the significant costs required to comply with environmental regulations. Urquhart Station is our oldest plant having been built in the 1950s. Units 1 and 2 were going to require significant expenditures to extend their life and to comply with environmental regulations. The Company engineers saw a way to use the same capital dollars to meet our capacity needs as well as to address some of the environmental issues. Three options were developed: 1) build two 150 MW CTs at COPE and upgrade Urquhart Units 1 and 2; 2) re-power Urquhart Units 1 and 2 as a combined cycle unit; and 3) build two 150 MW CTs at COPE and re-power Urquhart Units 1 and 2 as a fluidized bed coal unit.

Exhibit No._____(JML-5) shows the accumulated present worth of the comparative revenue required under each option. Under Option 1 the present value of revenue requirements is $384.6 million. This number includes the carrying charges on capital outlays related to extending the life of Urquhart Units 1&2, adding a Selective Catalytic Reduction (SCR) system at the COPE plant and adding two 150MW combustion turbines. The SCR at COPE would be required to offset the NOX emissions if units 1 &2 remained coal-fired. The present value also includes incremental O&M expenses, in particular, the incremental production costs over the combined cycle option.

Under Option 2 the present value of revenue requirements is $357.3 million. This number includes the carrying charges on the capital cost of the re-powering less those costs related to the chiller. The cost of the chiller was excluded because it added 41 Mws to Option 2 that were not present in the other options. Annual expenses related to the cost of firm transportation of gas are also included as part of Option 2 costs. The Company is planning to purchase 50,000 dekatherms of firm transportation capacity. Finally, under Option 3 the present value of revenue requirements is $473.2 million. This number includes the carrying charges on capital outlays related to re-powering Urquhart as a fluidized bed plant and adding two 150MW combustion turbines. It also includes the incremental production costs over Option 2. While the fluidized bed technology helps solve some of the emissions problems, it is too costly at the present time. Based on these results we can say that Option 2 is the least costly over the long run but that Option 1 is a close second.

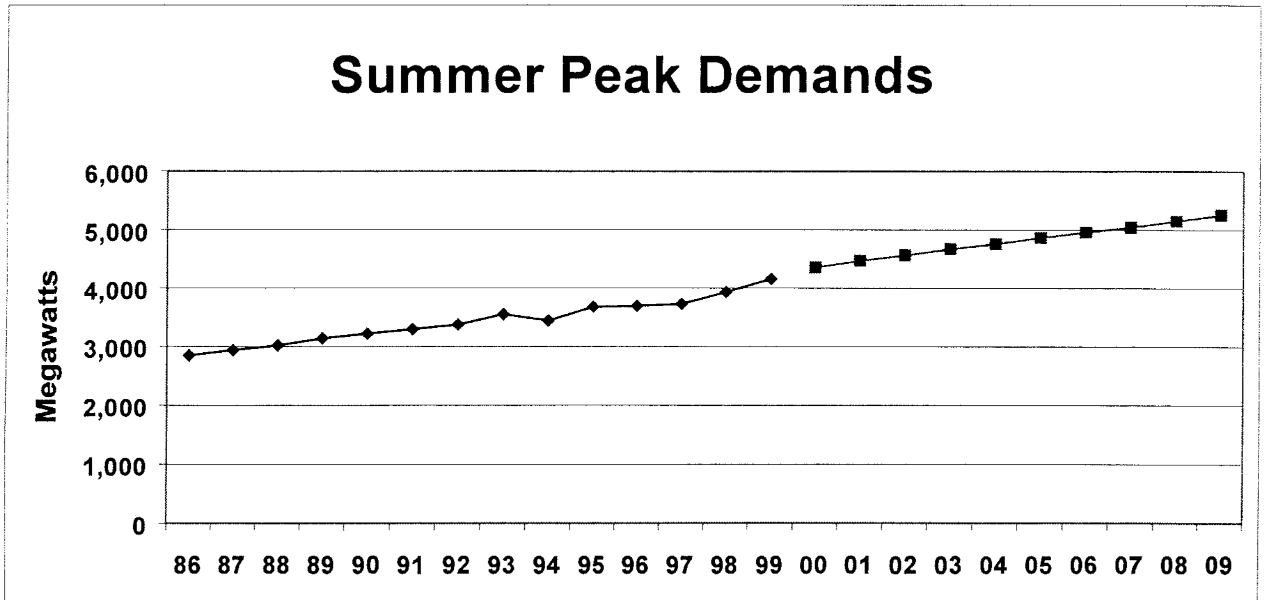
Q. What can you conclude in the short run?

A. In Exhibit No. _____(JML-6) the annual revenue requirement of each option is graphed. The graph shows that the revenue required for Option 2 starts off higher than Option 1 in 2002 but by 2005 it is the least costly option. The Company concluded that Option 2 is the preferred approach in part because of the above economic analysis and also because of the qualitative reasons discussed by Mr. Lorick and Mr. Preston.

Q. Does this conclude your testimony?

A. Yes it does.

Exhibit No. _____ (JML-1)



Year	Peak
85	2,703
86	2,853
87	2,943
88	3,021
89	3,144
90	3,222
91	3,300
92	3,380
93	3,557
94	3,444
95	3,683
96	3,698
97	3,734
98	3,935
99	4,158
00	4,355
01	4,468
02	4,562
03	4,669
04	4,754
05	4,863
06	4,956
07	5,042
08	5,144
09	5,251

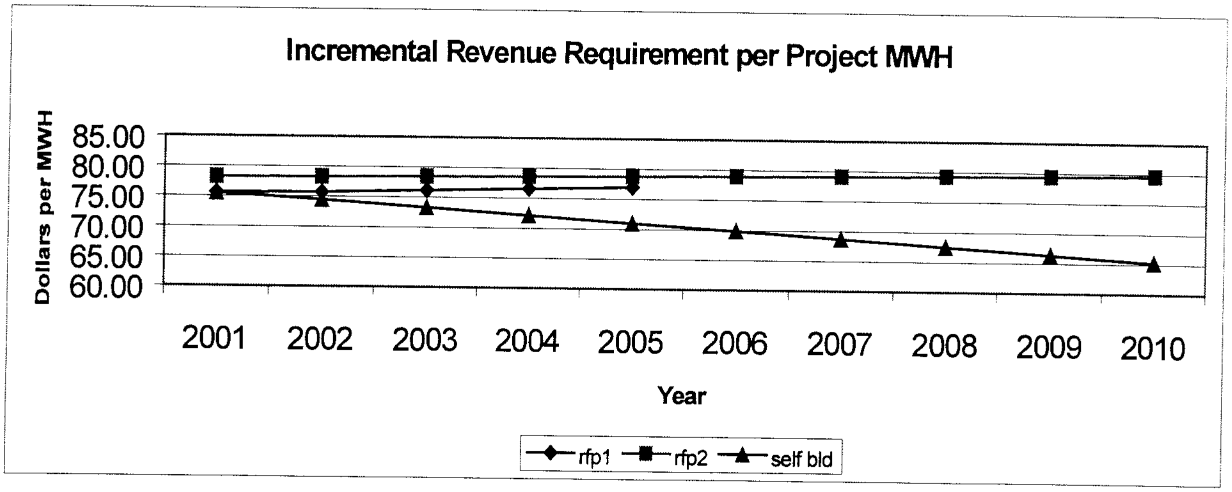
Exhibit No. ____(JML-2)

	Gross Peak (MW) (A)	DSM (MW) (B)	Firm Peak (MW) (C)	Target Reserve Margin (MW) (D)	Supply Required (MW) (E)	Existing Supply (MW) (F)	Supply Shortfall (MW) (G)
2000	4355	248	4,107	497	4,604	4,543	-61
2001	4468	248	4,220	497	4,717	4,543	-174
2002	4562	248	4,314	497	4,811	4,543	-268
2003	4669	248	4,421	497	4,918	4,543	-375
2004	4754	248	4,506	497	5,003	4,543	-460
2005	4863	248	4,615	497	5,112	4,543	-569
2006	4956	248	4,708	497	5,205	4,543	-662
2007	5042	248	4,794	497	5,291	4,543	-748
2008	5144	248	4,896	497	5,393	4,543	-850
2009	5251	248	5,003	497	5,500	4,543	-957

Exhibit No. _____ (JML-3)

2000 Planning Capacity	In-Service Date	Summer (MW)
Coal-fired Steam:		
Urquhart - Beech Island, SC	1953	250
McMeekin - near Irmo, SC	1958	252
Canadys - Canadys, SC	1962	435
Wateree - Eastover, SC	1970	700
Williams - Goose Creek, SC	1973	600
D-Area - USDOE Savannah River Site	1995	38
Cope - Cope, SC	1996	410
Cogen South – Charleston, SC	1999	55
Total Coal-fired Steam Capacity		2,740
Nuclear:		
V. C. Summer - Parr, SC	1984	635
I. C. Turbines:		
Burton, SC	1961	29
Faber Place - Charleston, SC	1961	10
Hardeeville, SC	1968	14
Urquhart - Beech Island, SC	1969	38
Coit - Columbia, SC	1969	30
Parr, SC	1970	60
Williams - Goose Creek, SC	1972	49
Hagood - Charleston, SC	1991	95
Urquhart No. 4 – Beech Island, SC	1999	48
Total I. C. Turbines Capacity		372
Hydro:		
Neal Shoals - Carlisle, SC	1905	5
Parr Shoals - Parr, SC	1914	14
Stevens Creek - Near Martinez, GA	1914	9
Columbia Canal - Columbia, SC	1927	10
Saluda - Near Irmo, SC	1930	206
Fairfield Pumped Storage - Parr, SC	1978	527
Total Hydro Capacity		771
Other: Purchases		25
Grand Total:		4,543

Exhibit No. _____ (JML-4)



years	rfp1	rfp2	self bld
2001	75.67	78.19	75.54
2002	75.79	78.33	74.48
2003	76.19	78.47	73.32
2004	76.59	78.62	72.16
2005	77.00	78.77	71.01
2006		78.93	69.85
2007		79.10	68.69
2008		79.26	67.54
2009		79.44	66.39
2010		79.61	65.23

Exhibit No. _____ (JML-5)

Options	Net Present Value of Comparative Revenue Requirements ($Million)
1) "URQ Coal" Upgrade Urquhart Units 1&2	384.6
2) "URQ CC" Re-power Urquhart as Combined Cycle	357.3
3) "URQ FB": Re-power Urquhart as Fluidized Bed	473.2

	URQ Coal	URQ CC	URQ FB
2000	2.7	0.0	0.0
2001	4.0	0.0	0.0
2002	38.8	54.8	57.5
2003	48.8	56.7	66.5
2004	48.1	55.2	64.2
2005	55.9	53.7	71.6
2006	56.0	52.1	71.0
2007	48.3	50.6	61.9
2008	58.0	49.0	70.2
2009	55.7	47.5	67.8
2010	51.9	45.9	63.3
2011	51.2	44.4	61.9
2012	50.5	42.8	60.5
2013	49.8	41.3	59.0
2014	49.0	39.7	57.6
2015	48.3	38.2	56.2
2016	47.6	36.6	54.8
2017	46.8	35.1	53.3
2018	46.1	33.5	51.9
2019	45.4	32.0	50.5
2020	44.1	30.4	49.1
2021	43.2	28.9	47.7
2022	42.3	27.3	46.3
2023	41.4	25.8	44.9
2024	40.5	24.3	43.5
2025	39.7	22.7	42.1
2026	38.5	21.2	40.7
2027	8.5	11.2	12.0
2028	1.4	0.0	0.0
2029	1.3	0.0	0.0
2030	1.1	0.0	0.0

Exhibit No. _____ (JML-6)